California Public Utilities Commission

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Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009

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I. Summary of Addendum

A. Background

On August 7, 2020, Energy Division staff issued an issue paper and straw proposal that included three potential solutions to address the emerging reliability and market power concerns identified in the paper. For reference, these reliability and market power concerns include the following:

- Retirements outpacing new resource additions in recent years, on a net qualifying capacity basis, which has significantly reduced reserve margins, and the lack of forward contracting (e.g., through multi-year tolling agreements) creating the opportunity for the exercise of system and local market power, particularly in the energy and resource adequacy (RA) markets;
- The fact that "peak capacity" is a regulatory construct – it is not the actual flowing of electrons or the curtailment of demand, it is a paper commitment to do so – and consequently a contractual commitment to provide peak capacity can be speculative in nature and potentially unreliable;
- A growing reliance on use limited resources (e.g., renewables, hydroelectric, pumped storage, batteries and other storage devices, demand response, etc.), coupled with the retirement of substantial amounts of the gas-fired generation that make it challenging to design a reliable hourly capacity construct;
- Growth in retail choice and the relationship with the provider of last resort makes it difficult to plan for reliability, if entities do not know whether they will be serving future load. This load uncertainty prevents entities from entering long-term contracts with new or existing resources; and
- Retirement of other assets throughout the West reduces imports that can be reliably counted on to serve California load during peak demand periods, which are often coincident throughout much of the West.

The following three potential solutions are detailed in Section IV of the Track 3.B Issue Paper and Straw Proposal. At a high level they can be summarized as follows:

1. Making several fundamental modifications to the existing capacity construct including revising the MCC buckets to make them binding in order to address issues associated with use-limited resources and revising the RA product to include a least-cost dispatch requirement or a bid cap;
2. Enhancing or replacing the current RA capacity / CAISO must-offer obligation construct with a forward energy based system and hourly load shape framework that requires load serving entities to demonstrate procurement of sufficient energy from specified physical resources that are contractually obligated to flow (or, in the case of DR, curtail) to meet their energy needs on a forward basis; or
3. Replacing the current RA capacity / CAISO must-offer obligation construct with a fixed price forward energy requirement similar to Option 2, but including a financial hedging component

that allows for risk arbitrage and price discovery on the part of generators, which can result in lower forward prices for customers.

B. Summary of Revisions

In this Addendum, staff provides revisions to the following sections of its initial issue paper and straw proposal:

- Section III: Staff provides additional data analysis on forward contracting positions drawn from load serving entities (LSEs') integrated resource planning (IRP) filing data.
- Section IV.A: Staff provides further detail regarding a proposed bid cap to be incorporated into the RA regulatory construct.
- Section IV.C: Staff provides further details to the Standard Forward Fixed Price Contract proposal (detailed in the IV. Appendix) which includes:
    - Explaining the changing supply mix in California and why a capacity-based approach is increasingly inappropriate for California;
    - How the true-up auctions would work to ensure 100% of actual demand is covered in standardized energy contracts;
    - How features of the existing capacity-based approach can be used in the standardized energy contracting-based approach; and
    - How to transitions from the capacity-based approach to the standardized energy contracting-based approach.

II. Supplemental Data Analysis of IRP Filings

A. Summary

In order to better understand the forward contracting landscape relative to the proposals put forth by Energy Division, staff performed a data analysis of the forward contracting positions of CPUC jurisdictional LSEs. The analysis includes energy and capacity positions of CPUC jurisdictional LSE collected from IRP data provided submitted on September 1, 2020. This analysis was conducted to better understand the short-medium term net open positions of LSEs and whether these positions are significant enough to warrant additional reliability requirements.

B. Data Description

For this analysis, staff used data from the IRP filings initially submitted by LSEs on September 1, 2020 and subsequently revised in October to include energy and RA only flags. The raw data includes information from 5,170 unique contracts from 60 LSEs for the years 2020 through 2030 inclusive. However, the analysis reflected below (and presented during the November 18th workshop) includes only data from the 40 CPUC-jurisdictional LSEs. Planned contracts were excluded from the data set since these contracts have not yet been executed. Finally, the time horizon of the data set is limited to years 2021-2024, which we consider the near- to medium-term contracting time horizon. In processing the data, staff learned that LSEs were inconsistently reporting Cost Allocation Mechanism (CAM) resources in their filings, which was leading to double-counting and inaccurate reporting. To resolve this issue, staff removed all CAM contracts from the raw data and re-allocated the total CAM amounts by LSE type, month, year, and resource type. The ratios used to allocate the CAM allocations by LSE type were derived from the 2021 Year-Ahead RA allocations.

The analysis looks at LSE open positions from both an energy and capacity perspective. For energy, we aggregated contracted GWhs by year, month, resource type, and LSE type, including the reallocated CAM discussed above. To develop the energy requirements for the LSE types, we use California Energy Commission's (CECs) Mid-Mid Hourly data distributed across LSE types using ratios derived from the Integrated Energy Policy Report (IEPR) Form 1.1c included in the most recent version of the Clean System Power Calculator – 46 MMT GHG. For capacity, we aggregated net qualifying capacity (NQC) MWs by year, month, resource type, and LSE type, including the reallocated CAM discussed above. To develop the RA capacity requirements, we used the CPUC RA requirements from the 2021 Year-Ahead RA Allocations for 2021 sent to LSEs in September 2021. The 2021 RA requirements are used in subsequent years (i.e. 2022 – 2024) as jurisdictional shares of monthly peak load data are not available. We have added the 15% Planning Reserve Margin (PRM) to the load forecast to calculate the RA requirement.

To provide consistency across multiple resource modeling paradigms, staff manually grouped contracts with similar resource types under a common name. These grouped contract resource types names include the following:

- Unspecified (includes unspecified non-imports, transfer purchases, transfer sales, and seller's choice contracts)
- Import
- Other (includes renewable energy credits and behind-the-meter energy efficiency contracts)
- Load Modifying
- Demand Response
- Thermal
- Hydro
- Hybrid
- Solar
- Wind
- Biomass/Biogas
- Biomass/Biomass
- Geothermal
- Nuclear
- Battery

We also note that this data only includes the contracts from the IRP filings. It does not include financial hedging products (such as call-options or futures) that could be used by LSEs to manage their open positions. It is also just a snapshot in time of the 2021-2024 positions, as LSEs get closer to serving load in real-time they may look to the short term markets for products to help manage their positions.

C. Analysis

Energy

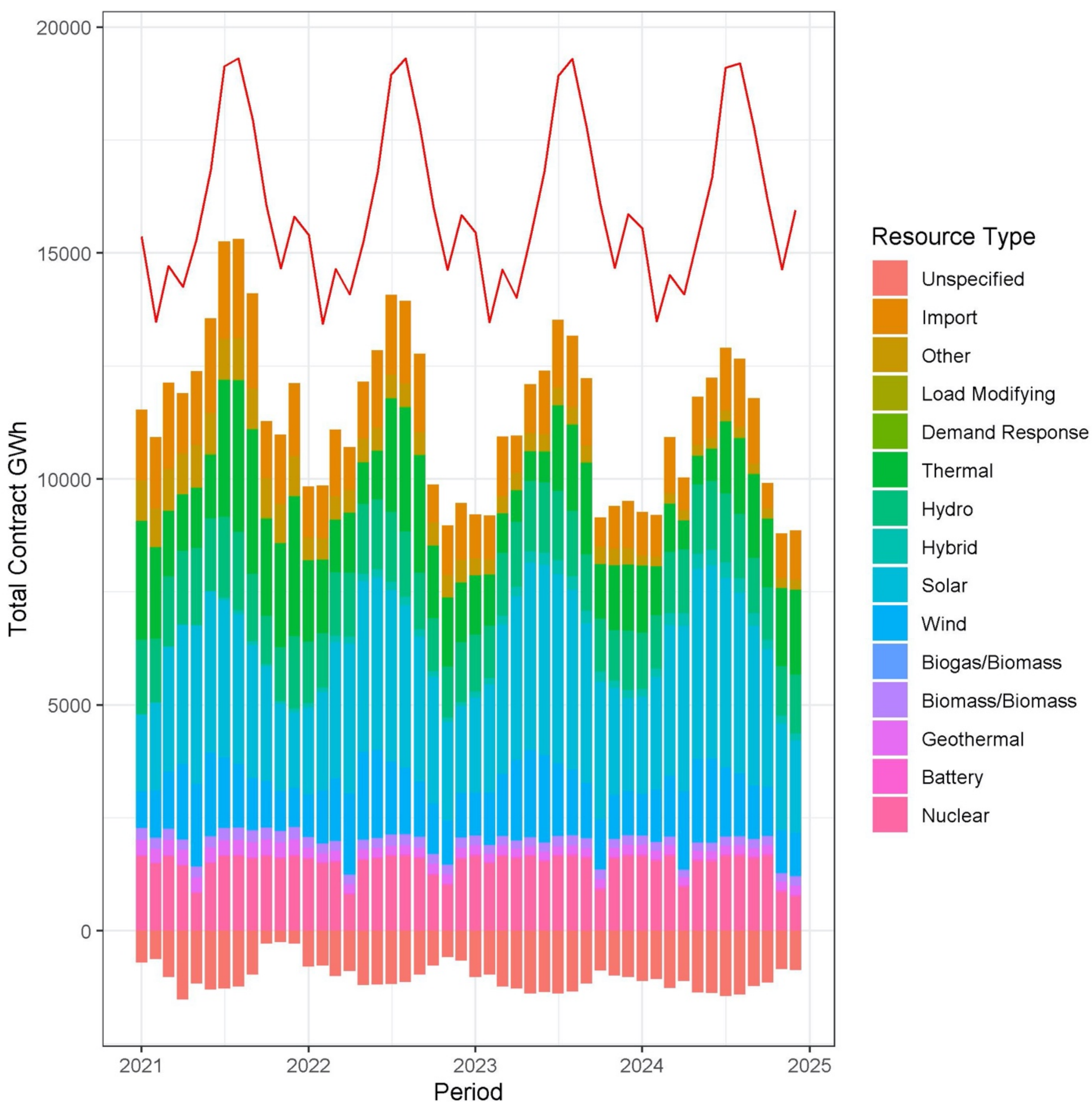
To examine energy positions, we aggregated the contracted GWh amounts for energy only contracts by year, month, resource type, and LSE type. We then compared this to the monthly aggregated CEC's Mid-Mid Hourly forecast for the share of load served by CPUC jurisdictional LSEs. Figure 1 below provides the stack of contracted resources by resource type for each month of the years 2021 through 2024. The red line in the graph is the monthly load forecast for each month. The available data show that, at the system level, there is insufficient energy contracted to meet load for all months between January 2021 through December 2024. Figure 1, below shows aggregate monthly contracted energy (GWhs) relative to the forecasted monthly energy requirements for CPUC jurisdictional LSEs for 2021-2024. On average for the years 2021 – 2024, about 65% of load can be met by currently contracted energy per month.[1] The negative unspecified values in red-orange are reflective of the sum of unspecified non-imports, transfer purchases, transfer sales, and seller's choice contracts resulting in a negative value. While we

[1] This average is calculated by taking the mean of the ratio of monthly contracted energy to monthly load forecast for each month from January 2021 to December 2024.

expect that sales and purchases would sum to zero, we would also expect that unspecified imports would be a positive value. Therefore, there is likely the misreporting of information in these values that will require further analysis and likely corrections to the data.

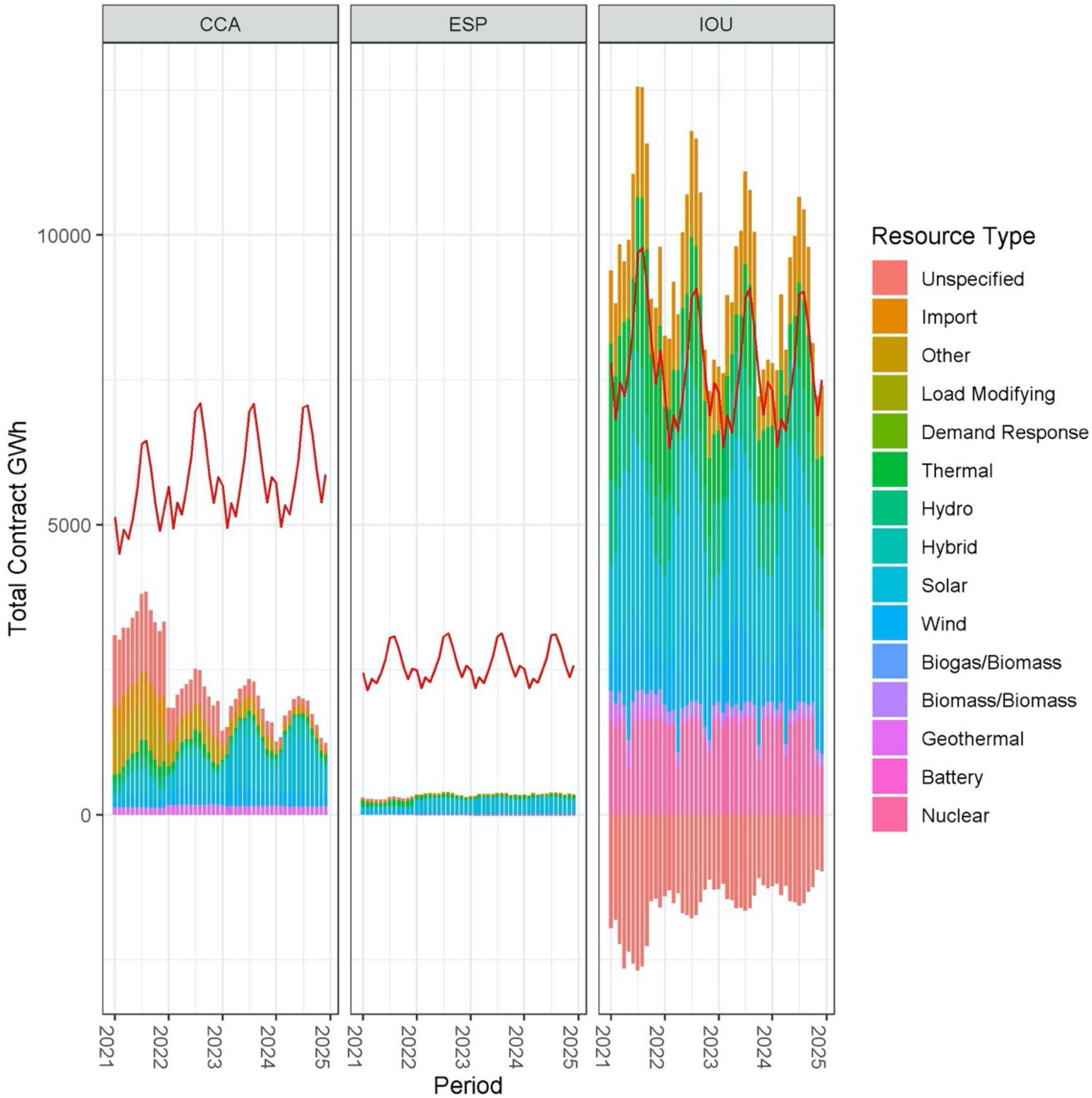
We also looked at open energy position by LSE type, shown in Figure 2 below. When broken down by LSE type, the data show that the IOUs are generally in a long position relative to their load forecast while CCAs and ESPs are generally short relative to their load forecasts. It should be noted that these LSE type positions do not incorporate any allocation of the future energy benefits that will be accounted for in

Figure 1. Total Contracted GWh each month by resource type, 2021-2024.



the Power Charge Indifference Adjustment (PCIA) mechanism. This means that some portion of the IOUs contracted energy benefits are going to CCAs and ESPs which would improve their energy positions relative to the figures presented below. However, we are not able to determine these amounts at this time. Additionally, a currently indeterminate portion of these contracted energy benefits are likely from solar resources so energy may not be available at the right times to meet load.

Figure 2. Total Contracted GWh each month by resource type and LSE Type, 2021-2024.



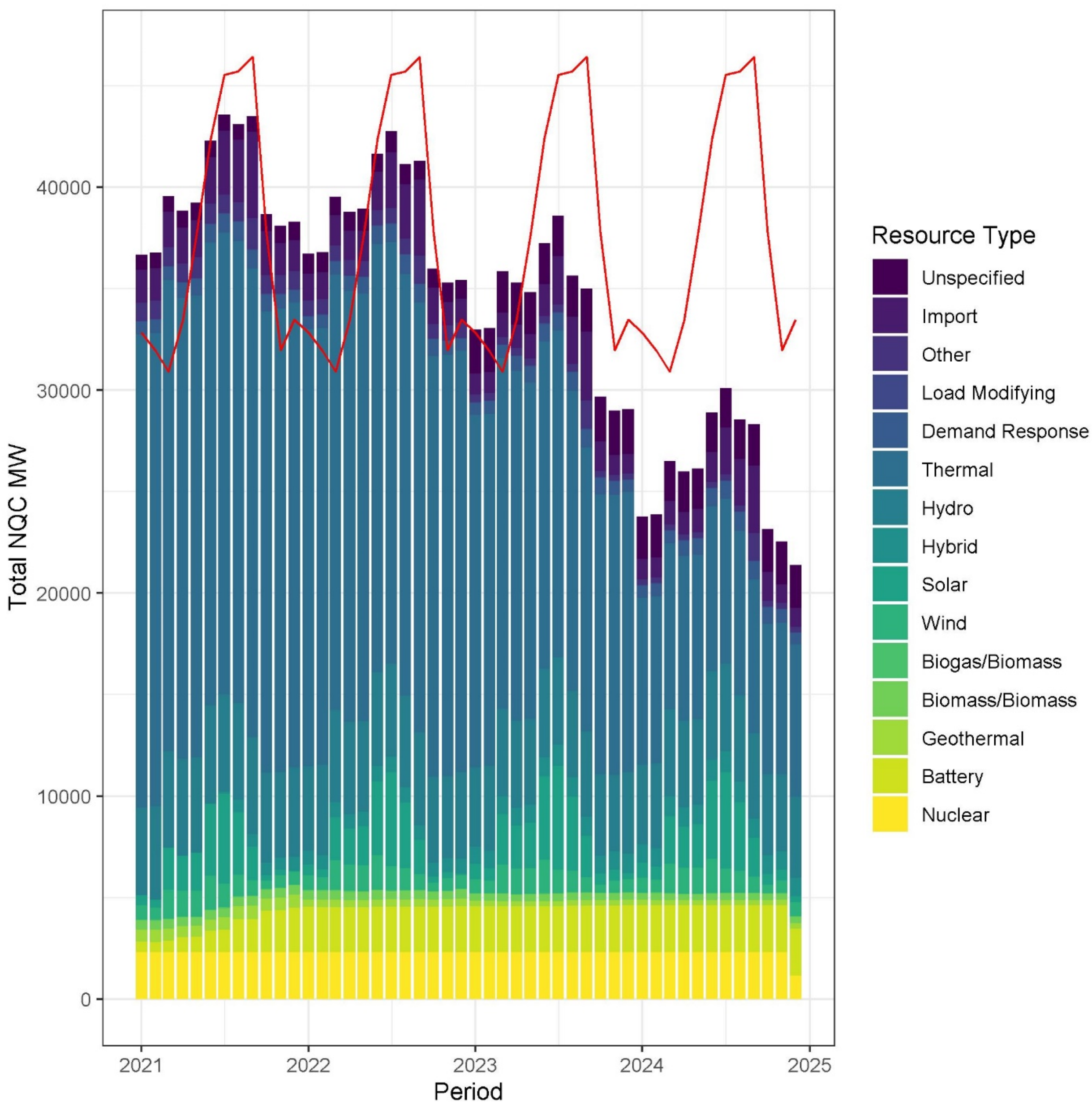
Capacity

To examine capacity at the system level, we looked at contracted NQC MWs reported by LSEs in the IRP filings. Like the energy analysis above, we aggregated the NQC MWs by year, month, and resource type and compared this to forecasted RA requirements for CPUC jurisdictional LSEs, which is the monthly maximum peak load plus a 15% planning reserve margin. To develop a high level proxy of forecasted RA requirements, we used the 2021 year ahead RA requirements that were allocated to jurisdictional LSEs on September 18, 2021. The 2021 allocations are used as a proxy for all of 2021-2024 as jurisdictional shares of monthly peak data are not available. Figure 3 shows the total monthly contracted NQC MWs compared to the forecasted monthly RA requirements broken down by resource type. As reflected in the Figure 3, in aggregate LSEs have procured between about 94% and 96% of their 2021 system peak RA requirements for July through September. These percentages decline slightly for 2022 and then drop more significantly in 2023 and 2024. The percentage of procurement for the summer months for 2021 through 2024 can be found in Table 1 below.

Table 1. RA procurement percentage for summer months, 2021 – 2024.

Year	July	August	September
2021	96%	94%	94%
2022	94%	90%	89%
2023	85%	78%	75%
2024	66%	62%	61%

Figure 3. Total NQC MW by month and resource type, 2021-2024.



To better understand the role that RA only contracts play in meeting RA requirements, we performed the same analysis looking at RA only contracts (Figure 4) and contracts that include energy in addition to capacity (Figure 5) again broken down by resource type. Figure 4 shows that for each month, the majority of contracted capacity comes from thermal resources and unspecified resources, there is no capacity contracted from nuclear resources, and RA only contracts decline from 32% in 2021 to 16% in 2024.

Figure 4. RA only contracts by month and resource type, 2021 – 2024.

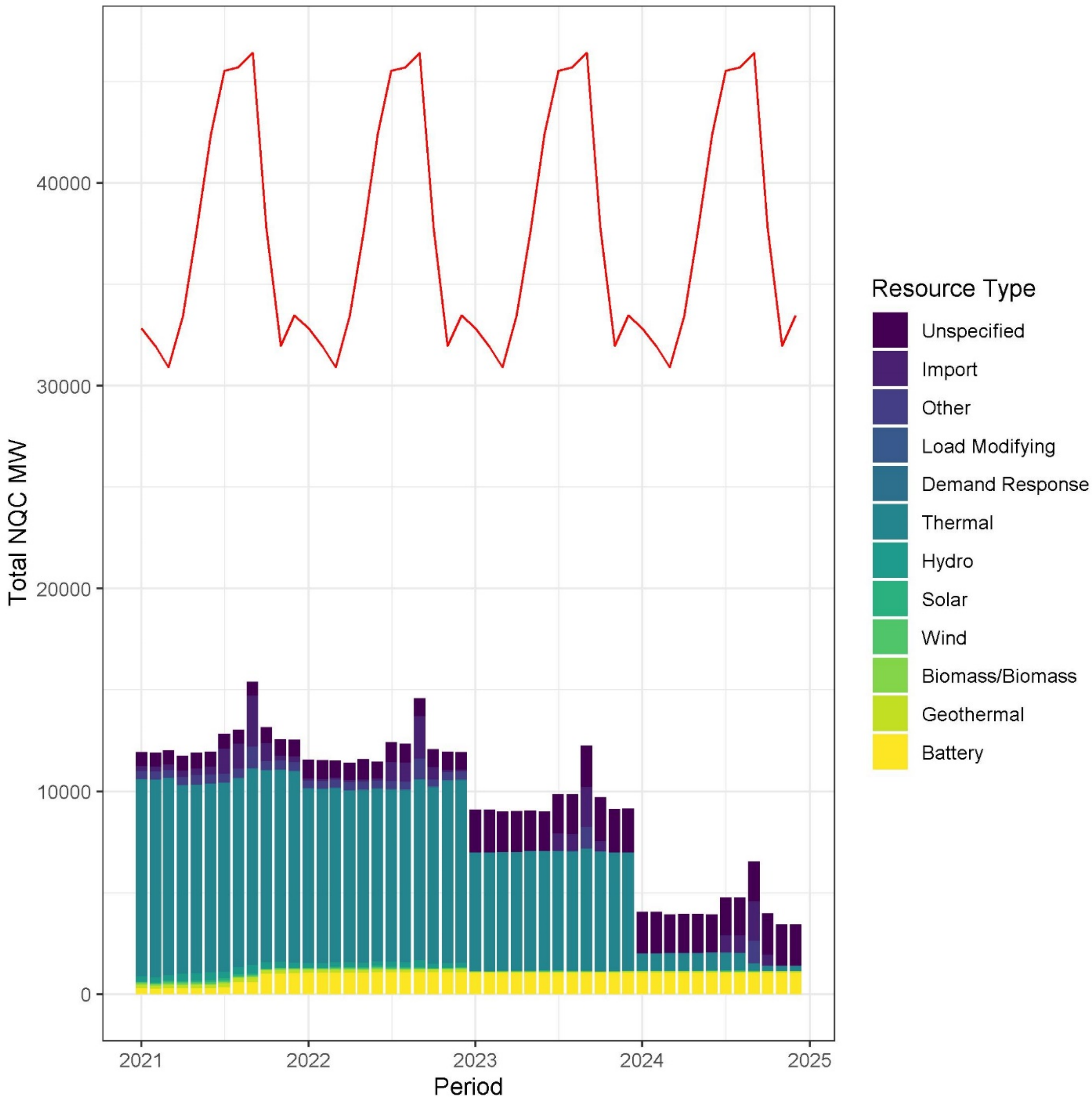


Figure 5 reflects the contracted NQC that includes energy in addition to capacity. These types of contracts include tolling arrangements, utility owned generation (nuclear, batteries, hydro, thermal), and long-term Power Purchase Agreements (PPAs) with renewable resources. A large portion of these resources are attributable to the IOU tolling agreements and utility owned generation (some of which are CAM resources) which can be seen in Figure 7. Figure 7 was initially published in the August 7th 2020 staff white paper (Figure 2) and reflects the same decline in energy contracting also highlighted in Figure 3 and 5 this proposal addendum.

Figure 5. Non-RA only contracts by month and resource type, 2021 – 2024.

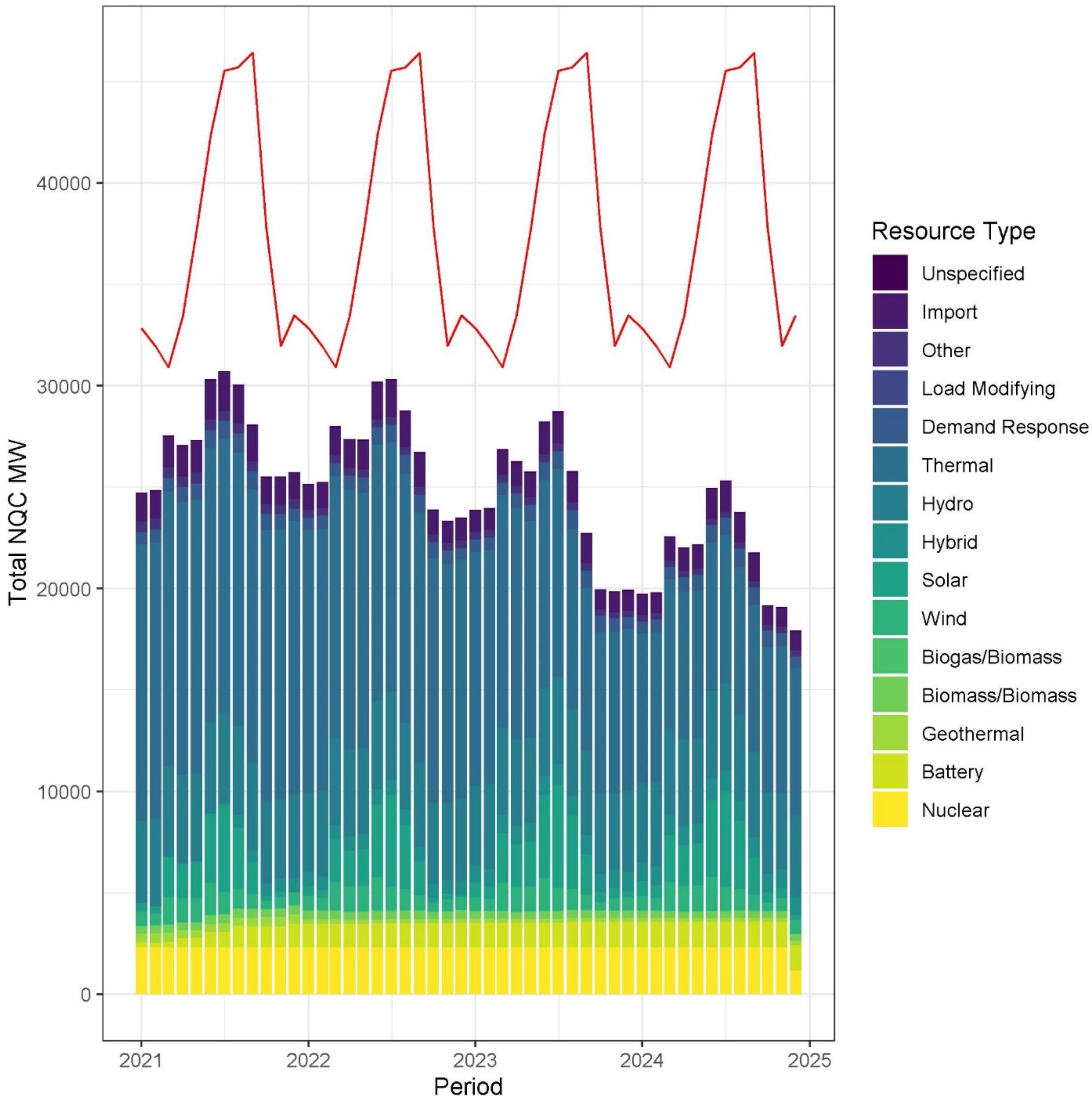


Figure 6 combines Figure 4 and 5 to illustrate the breakdown of the contracted NQC by RA only and the contracts that include energy and capacity. RA only resources reflect a similar trend over the 2021-2024 contract horizon, declining more sharply after 2023.

Figure 6. Contracted NQC by RA only and energy, 2021 – 2024.

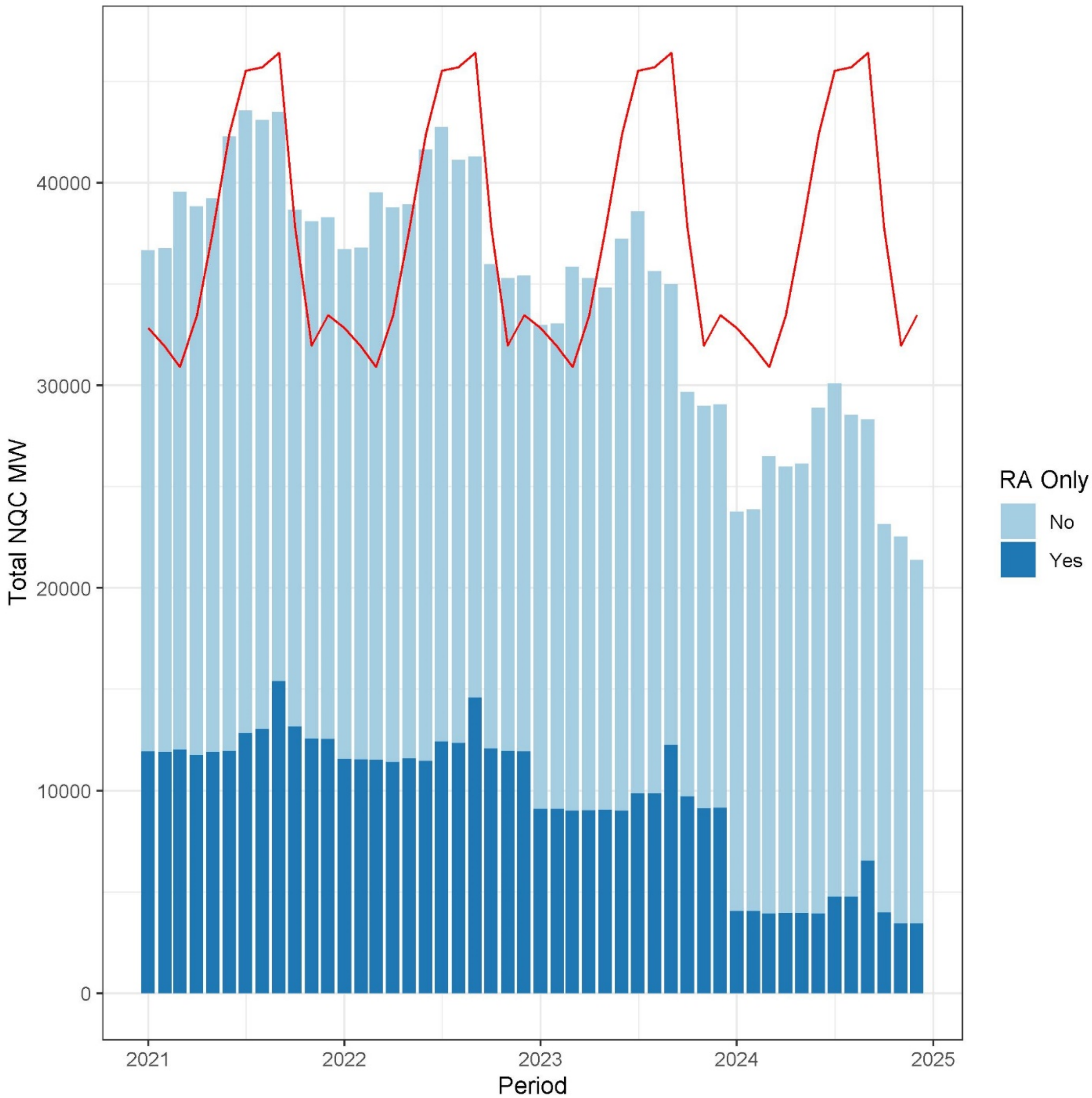
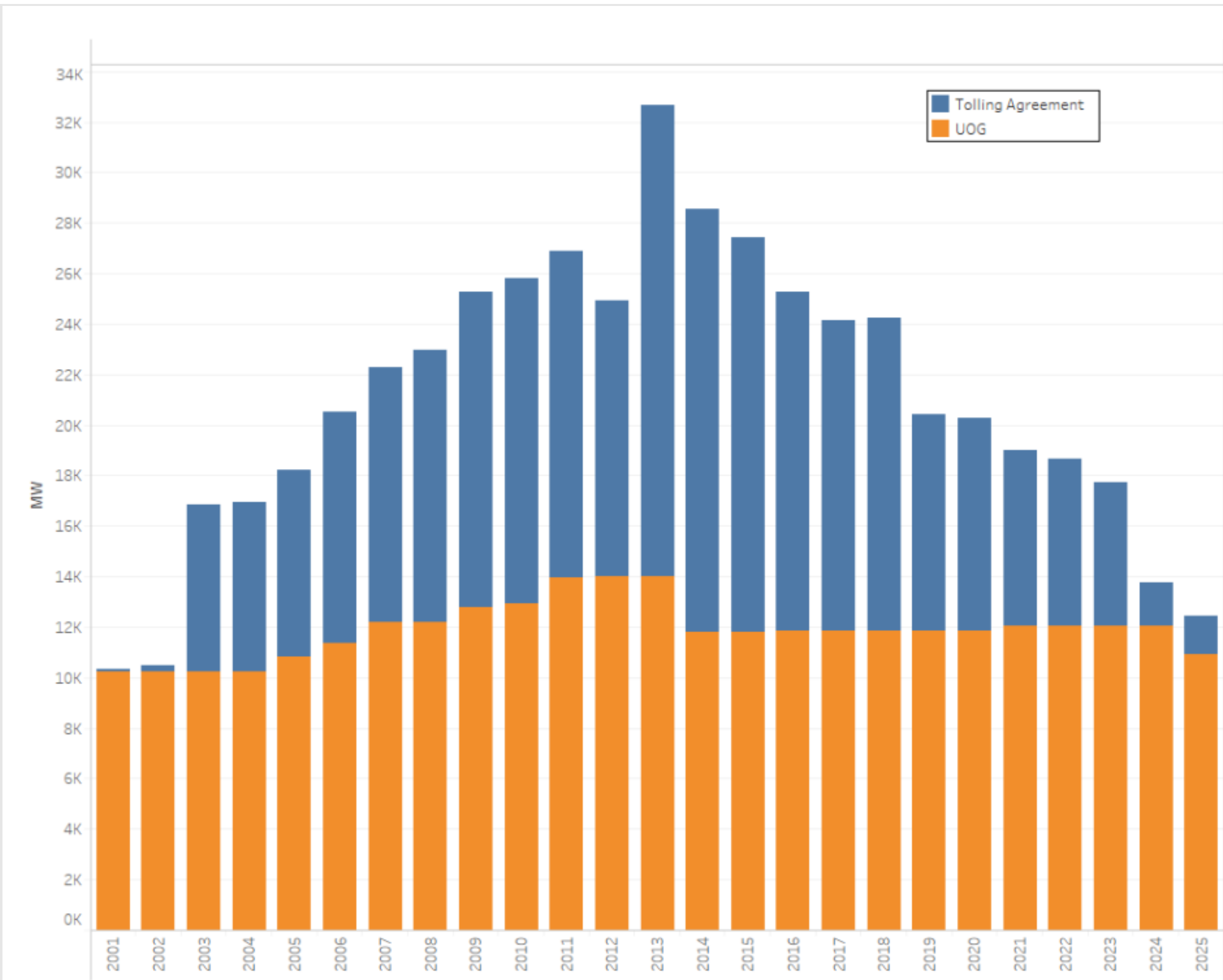


Table 2. Percentage of capacity that is contracted through RA Only Contracts and RA and Energy Contracts, 2021-2024.

Year	RA Only Contracts	RA and Energy Contracts
2021	32%	68%
2022	31%	69%
2023	28%	72%
2024	16%	84%

Figure 7. IOU Tolling Agreement and Utility Owned Generation by year, 2001-2025



D. Conclusion and Next Steps

The four primary conclusions from this analysis are that:

1. At an aggregate level, LSEs have only procured on average 65% of their forward energy positions for 2021-2024

2. At an aggregate level, LSEs have procured at least 90% of their system RA requirement through August 2022.
3. RA Only contracts make up 32% of contracted RA, and the large majority of the RA only is attributable to thermal and unspecified resources.
4. Capacity contracts that include energy are largely attributable to UOG and longterm tolling agreements reported by the IOUs. The data shows a sharp decline in 2024 as longterm tolling arrangements fall off contract.

Some of the next steps staff aims to undertake to better understand the forward contracting positions of LSEs and the implications that these positions have on future changes to the RA framework include:

- Model monthly IRP contract data at the hourly level using standard production profiles to better understand LSE hourly positions, especially from 4pm to 9pm.
- Examine why "unspecified" resources, when aggregated do not sum to a positive value and whether this is the result of LSE filing error.
- Examine other sources of data that could help staff better understand financial hedging products that are being used by LSEs to fill future open positions.

III. Further Detail Regarding a Proposed Bid Cap to be Incorporated into the RA Construct (Addendum to Section IV.A).

A. Background

In its issue paper and draft straw proposal, Energy Division staff proposed that, to address market power concerns, the CPUC could require least-cost dispatch bids or impose a bid cap for resource adequacy resources:

> To address market power, staff proposes that the CPUC could require least-cost dispatch bids or impose a bid cap for RA resources. As noted by CAISO's Market Surveillance Committee, SCE, and other parties, a bid cap could help to ensure that capacity contracted to meet California reliability needs and is indeed available to do so (e.g., could not bid at the $1000 - $2000 cap and thus not provide the capacity/energy when needed by the market). This requirement would prevent California ratepayers from paying for capacity that they do not receive, given that the RA program is intended to address system needs under normal operating conditions, whereas bidding at the current price cap of $1,000 per MWh (which will increase to $2,000 per MWh in the fall of 2021) basically ensures that the capacity will not provide customers with any benefits under normal operating conditions. While a bid cap does not ensure that RA resources will bid into the market at their marginal costs (similar to least cost dispatch requirements currently applicable to the IOUs under CPUC's jurisdiction), it does ensure that RA resources would be subject to a price cap on their bids which would be significantly lower than the current $1000/MWh (rising to $2000/MWh) FERC hourly bid cap. Issues to be resolved before implementing this second proposed modification include:
>
> • The level of the price cap;
>
> • How existing contracts would be treated;
>
> • How the CPUC could verify these bidding obligations if CAISO does not jointly implement such a proposal;
>
> • How the CPUC would enforce this (RA penalties if bidding does not comply); and
>
> • Whether there are any legal obstacles that would impede the CPUC from implementing such an approach and, if so, design changes that could address any such challenges.
>
> Staff intends to develop additional analysis on this aspect of the Fundamental Modifications to the Existing RA Construct option in the next iteration of this proposal.

B. Revisions to Proposal

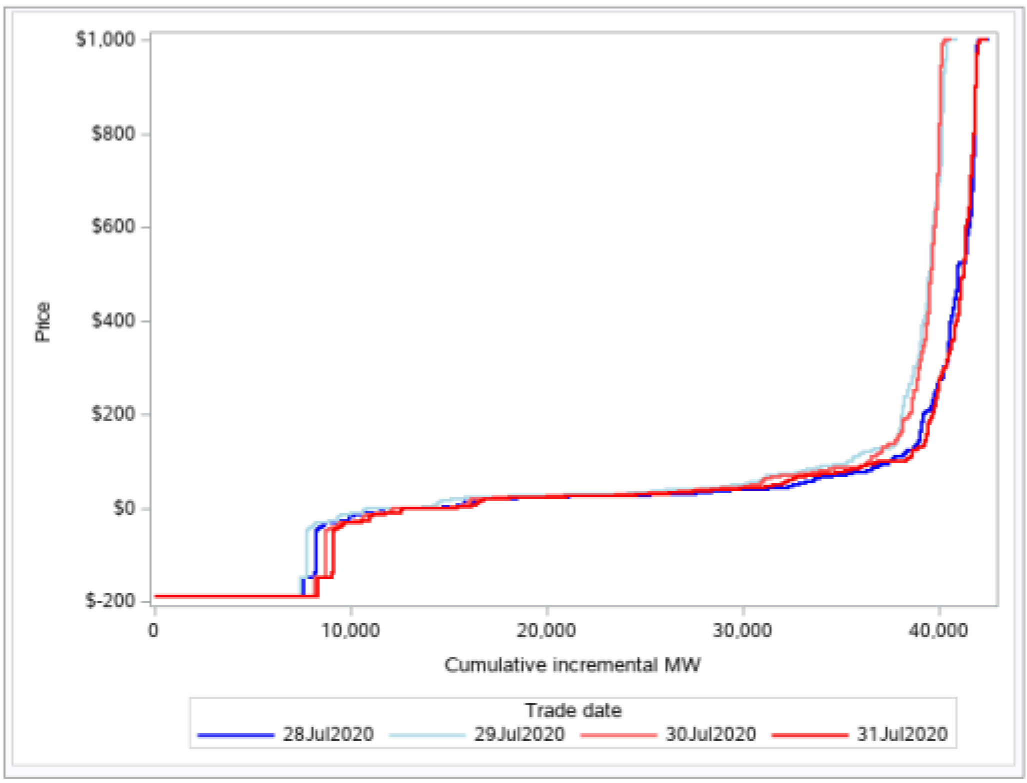
In this revision, Energy Division staff address each of these issues in turn.

i. The level of the price cap

Energy Division staff propose that the price cap be set at the higher of $300/MWh or the resource-specific default energy bid, excluding non-resource-specific default energy bids, such as those tied to indices. Resource adequacy resource are meant to be available at least 24 hours each month and resources bidding above $300/MWh (and considerably less than this is most circumstances) are unlikely to provide this level of availability. In addition, parties and stakeholders are likely to argue that this is not high enough to address potential gas market anomalies and, thus, Energy Division's staffs proposal is the higher of $300/MWh and the resource-specific default energy bid and that these default energy bids should capture any of these gas price anomalies.

In addition, we note the bid price curve associated with all resources during price spikes that occurred in July (see DMM's Figure 3.2 below from its Report on Market Competitiveness)[2], show that the vast majority of t resources had bids less than $300/MWh and, in any case, the default bid provision would cover bids that are higher than this level for gas-fired resources, as shown in Figures 3.11 and 3.12, from DMM's report (as shown below).

Figure 3.2 Supply bids (hour 20, July 28 - 31, 2020)



[2] California ISO, "Report on Day-Ahead Market Competitiveness: For July 30-31, 2020, Prepared by the Department of Market Monitoring, August 6, 2020. Available at [ReportonMarketCompetitivenessJul30-312020.pdf (caiso.com)]

Figure 3.11 Net buyers supply input bid and reference (hour 20, July 30, 2020)

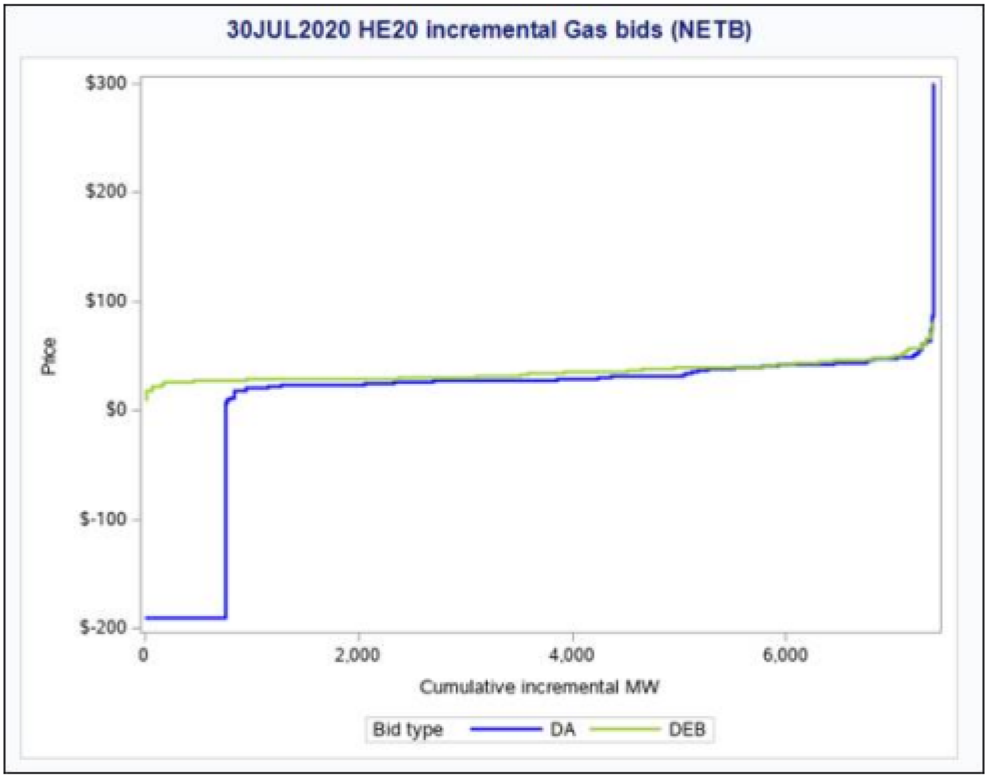
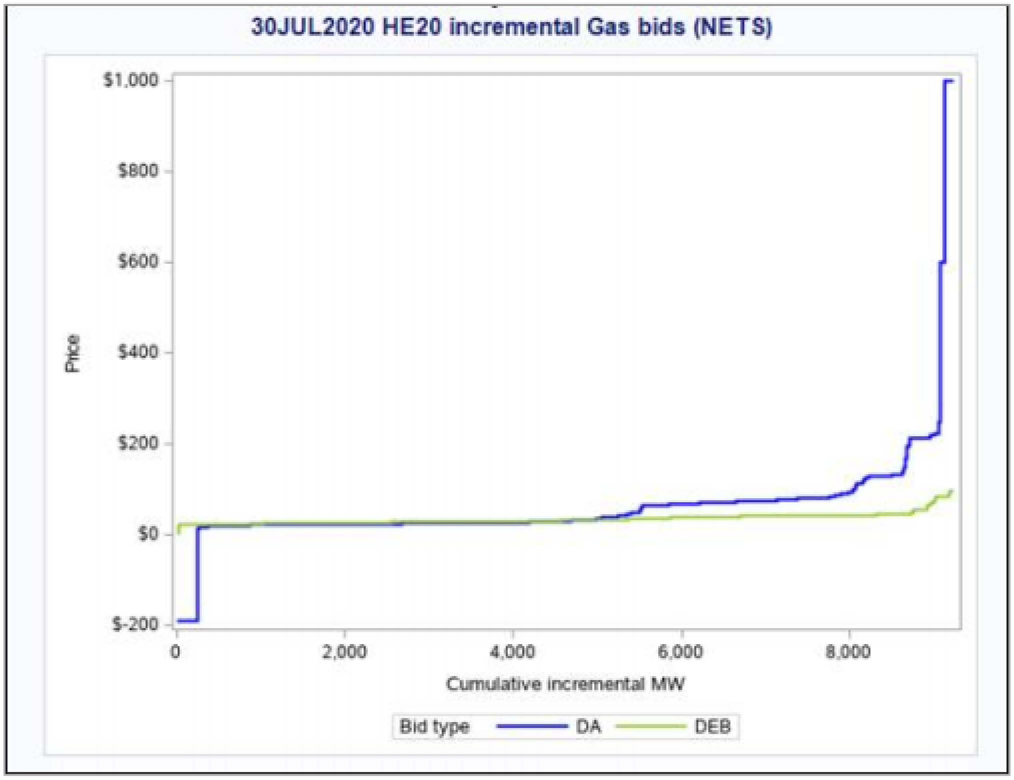


Figure 3.12 Net sellers supply input bid and reference (hour 20, July 30, 2020)



ii. How existing contracts would be treated.

Energy Division staff propose that this proposed change be implemented for resource adequacy compliance year 2023. This would allow market participants to revise contracts, to the extent necessary.

iii. How the CPUC could verify these bidding obligations if CAISO does not jointly implement such a proposal.

See discussion in the following section.

iv. How the CPUC would enforce this (RA penalties if bidding does not comply).

Energy Division staff propose a two-pronged enforcement mechanism. First, Energy Division staff propose that the Commission require that RA contracts include this bid cap provision (I.e., bidding no higher than the higher of $300/MWh or the default energy bid). Second, Energy Division staff propose to review bidding by market participants and refer load serving entities for non-RA compliance if the resources do not comply with the resource adequacy requirements per contractual provisions.

v. Whether there are any legal obstacles that would impede the CPUC from implementing such an approach and, if so, design changes that could address any such challenges.

Energy Division staff note that this resource adequacy requirement would not preclude non-resource adequacy capacity from bidding at any level and the requirement would be equally applicable to all resource adequacy resource types and, thus, should address any legal issues that could arise. Further, since Energy Division staff propose that the requirements be implemented in 2023, any legal issues that may arise could be addressed before implementation in 2023.

IV. Further Detail Regarding the Standard Fixed-Price Forward Energy Requirement (Addendum to Section IV.C)

A. Background

In its August 7, 2020 issue paper and draft straw proposal, Energy Division staff provided two straw proposals that included a fixed-price forward energy requirement. The second proposal can be summarized as:

"Replacing the current RA capacity / CAISO must-offer obligation construct with a fixed price forward energy requirement and including a financial hedging component that allows for risk arbitrage and price discovery on the part of generators, which can result in lower forward prices for customers."

Staff also included several questions that would need to be answered if the CPUC chose to move in this direction include:

- How the forward energy commitments would feed into CAISOs current market mechanism? For example, how and when would suppliers communicate what physical resources, they will be bidding into the short-term markets to meet their awarded SFPRC obligation?
- How such a mechanism would interact with other policy programs such as IRP and the Renewables Portfolio Standard (RPS)?
- What methodologies would be used to calculate the maximum available firm energy of resources?
- What role would LSEs play in serving load?
    - Would LSEs buy energy in the short-term markets to meet their load or would there no longer be a need to do this given the long-term forward energy procurement has already been procured?
    - What additional hedging products would be available to LSEs to compete on price?
- How would demand-side dispatchable resources participate in this framework? ○ Would CAISO buy dispatchable demand products as part of the standard product (via the auction)?
    - Would DR reduce hourly forecasted demand reducing the forward energy requirement (and an LSE's share of that requirement)?
- Would there be a way to modify this proposal to be an LSE based requirement rather than a central buyer requirement? What would be the benefits and drawbacks of this change (i.e. load migration, procurement autonomy)?
- Who would be the central buyer? If CAISO, should they agree, would CAISO being the central buyer raise jurisdictional concerns, and/or could jeopardize clean reliability mandates?
- What step would need to be taken to address local needs and constraints?
    - The CPUC recently adopted a centralized capacity framework for local RA in which SCE and PGE are acting as the CPE for their service territories.
    - Could we bridge this current framework with a forward energy system requirement? And if so, how?

B. Summary of Revisions

The revisions to this proposal include explaining the following:

- The changing supply mix in California and why a capacity-based approach is increasingly inappropriate for California;
- How the true-up auctions would work to ensure 100% of actual demand is covered in standardized energy contracts;
- How features of the existing capacity-based approach can be used in the standardized energy contracting-based approach; and

How to transitions from the capacity-based approach to the standardized energy contracting-based approach.

C. Revised Proposal- See Appendix

Appendix – "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California"

Long-Term Resource Adequacy in an Intermittent Renewable

and Import Dependent Future in California

by

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1. Introduction

Why is a capacity-based long-term resource adequacy mechanism an increasingly expensive approach to ensuring that the instantaneous supply of electricity equals the instantaneous demand throughout the year in California? First, the state has ambitious renewable energy goals that it plans to meet primarily with intermittent wind and solar resources. Second, California depends on imports for between 25 to 30 percent of its electricity. Third, this import dependence is particularly acute during system conditions when instate wind and solar generation units produce little electricity, as was demonstrated during the second half of August and early in September of 2020. Fourth, defining the firm capacity value of an intermittent renewable wind or solar resource is a difficult, if not impossible, task that becomes increasingly so as the share of wind and solar resources increases.

These factors argue in favor of a long-term resource adequacy mechanism that focuses on achieving what consumers want—the instantaneous supply of electricity equals the instantaneous demand for electricity throughout the year. This document presents a mandated standardized long-term contract for energy approach to achieving this goal. This mechanism can include features of the existing capacity-based mechanism, support retail competition, and reward active participation of final consumers in the wholesale electricity market.

Table 1 presents the installed capacity of grid scale wind and solar generation units in California as of the start of the year and the annual mean, median and standard deviation of the hourly output of these generation units. From 2013 and 2019, the installed capacity of grid scale wind and solar units increased by 328%. The annual median of hourly wind and solar energy production only increased by 231%, while the standard deviation of hourly wind and solar energy production increased 430%. The table also presents the annual coefficient of variation of hourly output (the ratio of the annual standard deviation divided by the annual mean) and the standardized skewness (the ratio of the average value of the mean-centered third power of hourly output divided by the third power of the standard deviation of hourly output). The coefficient of variation increases by 28% from 2013 to 2019 and standardized skewness increased by 326%. These changes in the distribution of hourly wind and solar output imply an increasingly uncertain supply of electricity in California between 2013 and 2019.

The sustained periods of low intermittent renewable energy production implied by the figures in Table 1 and California's dependence on electricity imports creates both a medium and long-term energy supply risk that requires a new long-term resource adequacy mechanism. The traditional capacity-based approach to long-term resource adequacy is unlikely to be the least cost mechanism for ensuring that the demand for energy is met throughout the year.

In a zero marginal cost intermittent future, wind and solar resources must hedge their energy supply risk with controllable generation resources in order to maintain long-term resource adequacy. Cross hedging between these technologies accomplishes two goals. First, it can provide the revenue stream necessary for fixed cost recovery by controllable generation units. Second, it ensures that there is sufficient controllable generation to meet demand under all foreseeable future system states, with a high degree of confidence.

Table 1: Capacity in MW and Features of Distribution of

Hourly Wind and Solar Output in MWh by Year

Year	2013	2014	2015	2016	2017	2018	2019
Mean	1348	2132	2510	3115	3869	4520	4617
Standard Deviation	883	1461	1983	2427	3258	3606	3818
Median	1364	1971	2031	2386	2596	3256	3150
Coefficient of Variation	0.65	0.69	0.79	0.78	0.84	0.80	0.83
Standardized. Skew	0.19	0.45	0.63	0.55	0.60	0.55	0.62
Standardized. Kurtosis	2.32	2.50	2.95	2.07	1.97	1.96	2.03
Capacity in (MW)*	4873	7698	9652	11,850	14,224	15,113	15,992

*As of the beginning of the year.

This paper presents a long-term resource adequacy mechanism for designed for an electricity supply industry with a large share of zero marginal cost intermittent renewables and substantial import dependence. I first explain why a wholesale electricity market requires a long-term resource adequacy mechanism. I then describe a mandated standardized long-term contract approach to long-term resource adequacy that provides strong incentives for intermittent renewable resource owners to hedge their energy supply risk with controllable generation resource owners. This mechanism ensures long-term resource adequacy in markets with retail competition while also allowing the short-term wholesale price volatility that can finance investments in storage and other load-shifting technologies necessary to manage a large share of intermittent renewable resources. Finally, I outline a process for transitioning to the mandated standardized long-term contract for energy mechanism and describe how this transition can utilize features of the existing capacity-based mechanism.

2. Resource Adequacy with Significant Intermittent Renewables

Why do wholesale electricity markets require a regulatory mandate to ensure long-term resource adequacy? Electricity is essential to modern life, but so are many other goods and services. Consumers want cars, but there is no regulatory mandate that ensures enough automobile assembly plants to produce these cars. They want point-to-point air travel, but there is no regulatory mandate to ensure enough airplanes to accomplish this. Many goods are produced using high fixed cost, low marginal cost technologies, similar to electricity supply. Nevertheless, these firms recover their cost of production, including a return on the capital invested, by selling their output at a market-determined price.

So, what is different about electricity that requires a long-term resource adequacy mechanism? The regulatory history of the electricity supply industry and the legacy technology for metering electricity consumption results in what I call a *reliability externality.*

2.1. The Reliability Externality

Different from the case of wholesale electricity, in the market for automobiles and air travel there is no regulatory prohibition on the short-term price rising to the level necessary to clear the market. Airlines adjust the prices for seats on a flight over time in an attempt to ensure that the number of customers traveling on that flight equals the number of seats flying. This ability to use price to allocate the available seats is also what allows the airline to recover its total production costs.

Using the short-term price to manage the real-time supply and demand balance in a wholesale electricity market is limited by a finite upper bound on a supplier's offer price and/or a price cap that limits the maximum market-clearing price. Although offer caps and price caps can limit the ability of suppliers to exercise unilateral market power in the short-term energy market, they also reduce the revenues suppliers can receive during scarcity conditions. This is often referred to as the *missing money* problem for generation unit owners. However, this missing money problem is only a symptom of the existence of the "reliability externality."

This externality exists because offer caps limit the cost to electricity retailers of failing to hedge their purchases from the short-term market. Specifically, if the retailer or large consumer knows the price cap on the short-term market is $250/MWh, then it is unlikely to be willing to pay more than that for electricity in any earlier forward market. This creates the possibility that real-time system conditions can occur where the amount of electricity demanded at or below the offer cap is less than the amount suppliers are willing to offer at or below the offer cap. This outcome implies that the system operator must be forced to either abandon the market mechanism or curtail load until the available supply offered at or below the offer cap equals the reduced level of demand, as occurred a number of times in California between January 2001 and April 2001, and most recently on August 14 and 15, 2020.

Because random curtailments of supply—also known as rolling blackouts—are used to make demand equal to the available supply at or below the offer cap under these system conditions, this mechanism creates a "reliability externality" because no retailer bears the full cost of failing to procure adequate amounts of energy in advance of delivery. A retailer that has purchased sufficient supply in the forward market to meet its actual demand is equally likely to be randomly curtailed as another retailer of the same size that has not procured adequate energy in the forward market. For this reason, all retailers have an incentive to under-procure their expected energy needs in the forward market.

The lower the offer cap, the greater is the likelihood that the retailer will delay their electricity purchases to the short-term market. Delaying more purchases to the short-term market increases the likelihood of insufficient supply in the short-term market at or below the offer cap. Because retailers do not bear the full cost of failing to procure sufficient energy in the forward market, there is a missing market for long-term contracts for energy with long enough delivery horizons into the future to allow new generation units to be financed and constructed to serve demand under all future conditions in the short-term market. Therefore, a regulator-mandated long-term resource adequacy mechanism is necessary to replace this missing market.

Some form of regulatory intervention is necessary to internalize the resulting reliability externality, unless the regulator is willing to eliminate or substantially increase the offer cap so that the short-term price can be used to equate available supply to demand under all possible future system conditions. This approach is taken by the Electricity Reliability Council of Texas (ERCOT), which has a $9,000/MWh offer cap, and National Electricity Market in Australia, which has a 15,000 Australia Dollars per MWh offer cap. However, raising the offer cap on the short-term market does not eliminate the reliability externality; it just reduces the set of future system conditions when random curtailments will be needed to balance real-time supply and demand. In addition, if customers do not have interval meters that can record their consumption on an hourly basis, then they have a very limited ability to benefit from shifting their consumption away from high-priced hours. All that can recorded for these customers is their total consumption between two successive meter readings so they can only be billed based on an average wholesale price during the billing cycle. Therefore, raising or having no offer cap on the short-term market would not be advisable in a region where few customers have interval meters. Even in regions with interval meters, there would be substantial political backlash from charging hourly wholesale prices that cause real-time demand to equal available supply under all possible future system conditions.

Currently, the most popular approach to addressing this reliability externality is a capacity procurement mechanism that assigns a firm capacity value to each generation unit based on the amount of energy it can provide under stressed system conditions. Under the current long-term resource adequacy mechanism in California, sufficient firm capacity procurement obligations are then assigned to retailers to ensure that annual system demand peaks can be met.

Capacity-based approaches to long-term resource adequacy rely on the credibility of the firm capacity measures assigned to generation units. This is a relatively straightforward process for thermal units. The nameplate capacity of the generation unit times its annual availability factor is a reasonable estimate of the amount of energy the unit can provide under stressed system conditions. For the case of hydroelectric facilities, this process is less straightforward. The typical approach uses percentiles of the distribution of past hydrological conditions for that generation unit to determine its firm capacity value.

Assigning a firm capacity value to a wind or solar generation unit is extremely challenging for several reasons. First, these units only produce when the underlying resource is available. If stressed system conditions occur when the sun is not shining or the wind is not blowing, these units should be credited with little, if any, firm capacity value. Second, because there is a high degree of contemporaneous correlation between the energy produced by solar and wind facilities within the same region, the usual approach to determining the firm capacity of a wind or solar unit assigns a smaller value to that unit as the total MWs of wind or solar capacity in the region increases. For example, on

August 14, 2020 the amount of wind energy produced from the almost 6,000 MW of wind capacity in California during the late evening when the rolling blackouts occurred was less than 700 MWh. In contrast, the effective load carrying capacity (ELCC) for wind units during August 2020 was set at 21 percent, which implies a firm capacity value of the 6,000 MW of wind capacity of more than 1200 MW. The trends in the annual distributions of hourly wind and solar output shown in Table 1 imply that these types of outcomes are increasingly likely in a capacity-based long-term resource adequacy mechanism as the share of intermittent wind and solar resources in California increases.

According to the California Energy Commission, the amount of natural gas-fired generation capacity in the state has declined by more than 8,500 MW between 2013 and 2019. This implies that when there are low levels of renewable energy production in California, the state must rely on electricity imports to serve demand. The out-of-state generation unit assumed to provide an electricity import is largely a purely financial construct because energy flows into the California because more energy is produced in the rest of Western Electricity Coordinating Council (WECC) than is being consumed there and less energy is being produced in California than is consumed in the state. Unless California builds additional controllable generation resources or makes substantial investments in energy storage, the state will be increasingly reliant on energy imports (that occur because more energy is produced outside of California that is being consumed outside of the state and not because a specific out-of-state generation unit is producing energy) particularly when instate renewable energy production is low. These trends provide further evidence against California continuing to rely on a capacity-based long-term resource adequacy mechanism.

2.2. Supplier Incentives with Fixed-Price Forward Contract Obligations for Energy

The standardized fixed-price forward contract (SFPFC) approach to long-term resource adequacy recognizes that a supplier with the ability to serve demand at a reasonable price may not do so if it has the ability to exercise unilateral market power in the short-term energy market. A supplier with the ability to exercise unilateral market power with a fixed-price forward contract obligation finds it expected profit maximizing to minimize the cost of supplying this forward contract quantity of energy. The SFPFC long-term resource adequacy mechanism takes advantage of this incentive by requiring retailers to hold hourly fixed-price forward contract obligations for energy that sum to the hourly value of system demand. This implies that all suppliers find it expected profit maximizing to minimize the cost of meeting their hourly fixed-price forward contract obligations, the sum of which equals the hourly system demand for all hours of the year.

To understand the logic behind the SFPFC mechanism, consider the example of a supplier that owns 150 MWs generation capacity that has sold 100 MWh in a fixed-forward contract at a price of $25/MWh for a certain hour of the day. This supplier has two options for fulfilling this forward contract: (1) produce the 100 MWh energy from its own units at their marginal cost of $20/MWh or (2) buy this energy from the short-term market at the prevailing market-clearing price. The supplier will receive $2,500 from the buyer of the contract for the 100 MWh sold, regardless of how it is supplied. This means that the supplier maximizes the profits it earns from this fixed-price forward contract sale by minimizing the cost of supplying the 100 MWh of energy.

To ensure that the least-cost "make versus buy" decision for this 100 MWh is made, the supplier should offer 100 MWh in the short-term market at its marginal cost of $20/MWh. This offer price for 100 MWh ensures that if it is cheaper to produce the energy from its generation units—the market price is at or above $20/MWh—the supplier's offer to produce the energy will be accepted in the short-term market. If it is cheaper to purchase the energy from the short-term market—the market price is below $20/MW—the supplier's offer will not be accepted and the supplier will purchase the 100 MWh from the short-term market at a price below $20/MWh.

This example demonstrates that the SFPFC approach to long-term resource adequacy makes it expected profit maximizing for each seller to minimize the cost supplying the quantity of energy sold in this forward contract each hour of the delivery period. By the logic of the above example, each supplier will find it in its unilateral interest to submit an offer price into the short-term market equal to its marginal cost for its hourly SFPFC quantity of energy, in order to make the efficient "make versus buy" decision for fulfilling this obligation.

If each supplier knows that the sum of the values of the hourly SFPFC obligations across all suppliers is equal the system demand, each firm knows that its competitors have substantial fixed-price forward contract obligations for that hour. This implies that all suppliers know that they have limited opportunities to raise the price they receive for short-term market sales beyond their hourly SFPFC quantity. For the above example, the supplier that owns 150 MWs of generation capacity has a strong incentive to submit an offer price close to its marginal cost to supply any energy beyond the 100 MWh of SFPFC energy it is capable of producing. Therefore, attempts by any supplier to raise prices in the short-term market by withholding output beyond their SFPFC quantity are likely to be unsuccessful because of the aggressiveness of the offers into the short-term market by its competitors with hourly SFPFC obligations.

2.3. SFPFC Approach to Resource Adequacy

This long-term resource adequacy mechanism requires all electricity retailers to hold SFPFCs for energy for fractions of realized system demand at various horizons to delivery. For example, retailers in total must hold SFPFCs that cover 100 percent of realized system demand in the current year, 95 percent of realized system demand one year in advance of delivery, 90 percent two-years in advance of delivery, 87 percent three years in advance of delivery, and 85 percent four years in advance of delivery. The fractions of system demand and number of years in advance that the SFPFCs must be purchased are parameters set by the regulator to ensure long-term resource adequacy. In the case of a multi-settlement LMP market, the SFPFCs would clear against the quantity-weighted average of the hourly locational prices at all load withdrawal nodes.

SFPFCs are shaped to the hourly system demand within the delivery period of the contract. Figure 1 contains a sample pattern of system demand for a four-hour delivery horizon. The total demand for the four hours is 1000 MWh, and the four hourly demands are 100 MWh, 200 MWh, 400 MWh and 300 MWh. Therefore, a supplier that sells 300 MWh of SFPFC energy has the hourly system demand-shaped forward contract obligations of 30 MWh in hour 1, 60 MWh in hour 2, 120 MWh in hour 3 and 90 MWh in hour 4 for Firm 1 in Figure 2. The hourly forward contract obligations for Firm 2 that sold 200 MWh SFPFC energy and Firm 3 that sold 500 MWh of SFPFC energy are also shown in Figure 2.

These SFPFC obligations are also allocated across the four hours according to the same four hourly shares of total system demand. This ensures that the sum of the hourly values of the forward contract obligations for the three suppliers is equal to the hourly value of system demand. Taking the example of hour 3, Firm 1's obligation is 120 MWh, Firm 2's is 80 MWh and Firm 3's is 200 MWh. These three values sum to 400 MWh, which is equal to the value of system demand in hour 3 shown in Figure 1.

These standardized fixed-price forward contracts are allocated to retailers based on their share of system demand during the month. Suppose that the four retailers in Figure 3 consume 1/10, 2/10, 3/10, and 4/10, respectively, of the total energy consumed during the month. This means that Retailer 1 is allocated 100 MWh of the 1000 MWh SFPFC obligations for the four hours, Retailer 2 is allocated 200 MWh, Retailer 3 is allocated 300 MWh, and Retailer 4 is allocated 400 MWh. The obligations of each retailer are then allocated to the individual hours using the same hourly system demand shares used to allocate the SFPFC energy sales of suppliers to the four hours. This allocation process implies Retailer 1 holds 10 MWh in hour 1, 20 MWh in hours 2, 40 MWh in hour 3 and 30 MWh in hour 4. Repeating this same allocation process for the other three retailers yields the remaining three hourly allocations shown in Figure 3. Similar to the case of the suppliers, the sum of allocations across the four retailers for each hour equals the total hourly system demand. For period 3, Retailer 1's holding is 40 MWh, Retailer 2's is 80 MWh, Retailer 3's is 120 MWh, and Retailer 4's is 160 MWh. The sum of these four magnitudes is equal to 400 MWh, which is the system demand in hour 3.

2.4. Mechanics of Standardized Forward Contract Procurement Process

The SFPFCs would be purchased through auctions several years in advance of delivery in order to allow new entrants to compete to supply this energy. Because the aggregate hourly values of these SFPFC obligations are allocated to retailers based on their actual share of system demand during the month, this mechanism can easily accommodate retail competition. If one retailer loses load and another gains it during the month, the share of the aggregate hourly value of SFPFCs allocated to the first retailer falls and the share allocated to the second retailer rises.

The wholesale market operator would run the auctions with oversight by the regulator. One advantage of the design of the SFPFC products is that a simple auction mechanism can be used to purchase each annual product. A multi-round auction could be run where suppliers submit the total amount of annual SFPFC energy they would like to sell for a given delivery period at the price for the current round. Each round of the auction the price would decrease until the amount suppliers are willing to sell at that price is less than or equal to the aggregate amount of SFPFC energy demanded.

The wholesale market operator would also run a clearinghouse to manage the counterparty risk associated with these contracts. All US wholesale market operators currently do this for all participants in their energy and ancillary services markets. In several US markets, the market operator also provides counterparty risk management services for long-term financial transmission rights, which is not significantly different from performing this function for SFPFCs.

SFPFCs auctions would be run on an annual basis for deliveries starting two, three, and four years in the future. In steady state, auctions for incremental amounts of each annual contract would also be needed so that the aggregate share of demand covered by each annual SFPFC could increase over time. The eventual 100 percent coverage of demand occurs through a final true-up auction that takes place after the realized values for hourly demand for the delivery period are known.

The following two examples illustrate how the true-up auctions would work. Assume for simplicity, the monthly load shares of the four retailers remain unchanged. Suppose that the initial 1000 MWh SFPFC in the above example sold at $50/MWh. However, suppose that actual demand turned out to be 10 percent higher in every period as shown Figure 4 and the additional 100 MWh purchased in the true-up auction sold at $80/MWh. If each firm sold 10 percent more SFPFC energy in the true-up auction this would yield the hourly obligations for each supplier shown in Figure 5. The hourly obligations for the four retailers are shown in Figure 6. These would clear against the average cost of purchases from the original auction and true-up auction of $52.73.

If the realized hourly demands are ten percent lower as shown in Figure 7, the true-up auction would buy back 100 MWh of SFPFC energy. If all suppliers bought back 10 percent of their initial sales at $20/MWh, the resulting hourly obligations would be those shown in Figure 8. The 10 percent smaller hourly obligations of the four retailers are shown in Figure 9 and these would clear against the average cost of the initial auction purchase less the revenues from the true-up auction sales for the required 900 MWh of obligations of $53.33.

As shown in Figures 6 and 9, each purchase or sale of the same annual SFPFC product is allocated to retailers according to their load shares during the delivery month. If three different size purchases are made for the same annual SFPFC product at different prices, then each retailer is allocated its load share for the month of these three purchases. This ensures a level playing field for retailers with respect to their long-term resource adequacy obligation. All retailers face the same average price for the long-term resource adequacy obligation associated with their realized demand for the month.

The advance purchase fractions of the final demand are the regulator's security blanket to ensure that system demands can be met for all hours of the year for all possible future system conditions. If the regulator is worried that not enough resources will be available in time to satisfy this requirement, it can increase the share of final demand that it purchases in each annual SFPFC auction. As shown above, if too much SFPFC energy is purchased in an annual auction, it can be sold back to generation unit owners in a later auction or the final true-up auction.

2.5. Incentives for Behavior by Intermittent Renewable and Controllable Resources

Because all suppliers know that all energy consumed every hour of the year is covered by a SFPFC in the current year and into the future, there is a strong incentive for suppliers to find the least cost mix intermittent and controllable resources to serve these hourly demands. To the extent that there is concern that the generation resources available or likely to be available in the future to meet demand are insufficient, features of the existing capacity-based resource adequacy mechanism can be retained until system operators have sufficient confidence in this mechanism leading to a reliable supply of energy. The firm capacity values from the existing capacity-based long-term resource adequacy approach can be used to limit the amount of SFPFC energy a supplier can sell.

The firm capacity value multiplied by number of hours in the year would be the maximum amount of SFPFC energy that the unit owner could sell in any given year. Therefore, a controllable thermal generation unit owner could sell significantly more SFPFC energy than it expects to produce annually and an intermittent renewable resource owner could sell significantly less SFPFC energy than it expects to produce annually. This upper bound on the amount of SFPFC energy any in-state generation unit could sell enforces cross hedging between controllable in-state generation units and intermittent renewable resources.

The current capacity-based requirements on out-of-state suppliers could put limitations on the maximum amount of SFPFC energy they could sell in a year. For example, if an out-of-state supplier has 10 MWs of firm capacity not committed to provide energy to consumers in its home state, then it could sell at most 87,600 MWh of SFPFC on an annual basis.

This mechanism uses the firm capacity construct to limit forward market sales of energy by individual resource owners to ensure that it is physically feasible to serve demand throughout California during all hours of the year, but only purchases the commodity that consumers want energy. Because all suppliers know that system demand each hour of the year is covered by a SFPFC purchased in advance of delivery (except for the true-up quantities discussed earlier), collectively suppliers have a strong financial incentive to find the least cost way to serve this demand, regardless of real-time system conditions.

In most years, a controllable resource owner would be producing energy in a small number of hours of the year, but earning the difference between the price at which they sold the energy in the SFPFC auction and the hourly short-term market price times the hourly value of its SFPFC energy obligation for all the hours that it does not produce energy. Intermittent renewables owners would typically produce more than their SFPFC obligation in energy and sell the additional energy at the short-term price. In years with low renewable output near their SFPRC obligations, controllable resource owners would produce close to the hourly value of their SFPFC energy obligation, thus making average short-term prices significantly higher. However, aggregate retail demand would be shielded from these high short-term prices because of their SFPC holdings.

2.4. Advantages of SFPFC Approach to Long-Term Resource Adequacy

This mechanism has a number of advantages relative to a capacity-based approach. There is no regulator-mandated aggregate capacity requirement. Generation unit owners are allowed to decide both the total MWs and the mix of technologies to meet their SFPFC energy obligations. There is also no prohibition on generation unit owners or retailers engaging in other hedging arrangements outside of this mechanism. Specifically, a retailer could enter into a bilateral contract for energy with a generation unit owner or other retailer to manage the short-term price and quantity risk associated with the difference between their actual hourly load shape and the hourly values of their retail load obligation.

This mechanism provides a nudge to market participants to develop a liquid market for these bilateral contract arrangements at horizons to delivery similar to the SFPFC products. Instead of starting from the baseline of no fixed-price forward contract coverage of system demand by retailers, this mechanism starts with 100 percent coverage of system demand, which retailers can unwind at their own risk.

This baseline level of SFPFC coverage of final demand is a more prudent approach to long-term resource adequacy in a region such as California where the vast majority of customers purchase their electricity according to a fixed retail price or price schedule that does not vary with real-time system conditions. A baseline 100 percent SFPFC coverage of final demand provides the retailer with wholesale price certainty for virtually all of its wholesale energy purchases (except for the small true-up uncertainty described above), that significantly limits the financial risk retailers faces from selling retail electricity at a fixed price and purchasing this energy from a wholesale market with increasingly volatile wholesale prices.

An additional benefit of this mechanism is that the retail market regulator, this case the California Public Utilities Commission (CPUC), can use the purchase prices of SFPFCs to set the wholesale price implicit in the regulated retail price over the time horizon that the forward contract clears. This would provide retailers with a strong incentive to reduce their average wholesale energy procurement costs below this price through bilateral hedging arrangements, storage investments, or demand response efforts.

There are several reasons why this mechanism should be a more cost-effective approach to long-term resource adequacy than a capacity-based mechanism in a zero marginal cost intermittent future. First, the sale of SFPFC energy starting delivery two or more years in the future provides a revenue stream that will significantly increase investor confidence in recovering the cost of any investment in new generation capacity.

Second, because retailers are protected from high short-term prices by total hourly SFPFC holdings equal to system demand, the offer cap on the short-term market can be raised in order to increase the incentive for all suppliers to produce as much energy as possible during stressed system conditions. Third, the possibility of higher short-term price spikes can finance investments in storage and load-shifting technologies and encourage active participation of final demand in the wholesale market, further enhancing system reliability in a market with significant intermittent renewable resources.

If SFPFC energy is sold for delivery in four years based on a proposed generation unit, the regulator should require construction of the new unit to begin within a pre-specified number of months after the signing date of the contract or require posting of a substantially larger amount of collateral in the clearinghouse with the market operator. Otherwise, the amount of SFPFC energy that this proposed unit sold would be automatically liquidated in a subsequent SFPFC auction and a financial penalty would be imposed on the developer. Other completion milestones would have to be met at future dates to ensure the unit is able to provide the amount of firm energy that it committed to provide in the SFPFC contract sold. If any of these milestones were not met, the contract would be liquidated.

3. Transition to SFPFC Mechanism in California

With sufficient advance notice, transitioning to the SFPFC approach to long-term resource adequacy in California would be relatively straightforward because, as noted above, this mechanism makes use of features of the existing capacity-based mechanism. The first step in the transition would be a plan for phasing out the existing capacity-based mechanism in four years. SFPFC auctions for delivery in four years would then be run. This would provide sufficient advance notice for market participants to adapt the mix of supply resources to the new long-term resource adequacy mechanism.

All SFPFCs would clear against the quantity-weighted average of real-time locational marginal prices (LMPs) at all load-withdrawal nodes in California. By the logic described above, this would ensure that all sellers of SFPFCs collectively have a strong incentive to ensure that real-time demands, not the day-ahead demands, at all locations in California are met at least cost. Retailers would face some locational short-term price risk because of differences between this price and the load aggregation point (LAP) price they are charged for purchases of energy from the short-term market. Financial transmission rights could be allocated to loads to hedge a significant fraction of this residual locational price risk.

Each subsequent year in the transition, another SFPFC auction for energy to be delivered in four years would be run. Incremental SFPFC auctions for deliveries in three, two and one year would also be run to achieve aggregate SFPFC quantities that satisfy the increasing advance purchase percentages of realized system demand described earlier. The clearinghouse would adjust collateral requirements of the sellers and buyers of these SFPFCs throughout the year to ensure that each side of the transaction will fulfill their obligation when these contracts clear. Once the first year that the SFPFC obligations clear, there would also be a true-up auction to ensure 100% coverage of realized demand.

It is important to emphasize how this mechanism provides financial incentives to serve the demand at all locations in California at least cost. Because all SFPFCs clear against the quantity-weighted average of the hourly real-time LMPs, sellers of SFPFCs collectively have a financial incentive to ensure that nodal price spikes do not occur because of a local scarcity condition or other local reliability event.

The following example illustrates this incentive. Suppose a supplier that owns a 150 MWh unit located in a generation pocket has sold 100 MWh of SFPFC energy for $50/MWh, but only small fraction of this energy is consumed at nearby nodes. Suppose that the price spikes at a one or more load nodes and this leads to a quantity-weighted average LMP of $500/MWh. Suppose this supplier was able to sell 100 MWh in the short-term market in this generation pocket for $40/MWh. In this case, the supplier's variable profit is ($40/MWh - $30/MWh)*100 MWh – ($500/MWh - $50/MWh)*100 MWh, assuming its marginal cost is $30/MWh. Consequently, even if the supplier is able to sell its SFPFC quantity of energy in the short-term market, the second term in the supplier's variable profits that results from clearing of the its SFPFC obligations provides a strong incentive for it to take actions to ensure that price spikes at load withdrawal nodes do not occur. Transmission constraints out of the generation pocket that limit the amount of energy the supplier can sell in the short-term market further reduce the supplier's variable profits. This fact implies an additional incentive for sellers of SFPFCs to serve system demand at least cost.

To the extent that there is concern that these financial incentives are insufficient for generation unit owners to address all local reliability issues, separate SFPFC products could be created for regions of the state. For example, there could separate SFPFCs for the demand nodes in Northern California and the demand nodes in Southern California. Only suppliers with the ability to deliver energy from their capacity to demand in Northern California could sell in the Northern California SFPFC auction. A similar requirement would apply for sellers in the Southern California SFPFC auction. The Northern California SFPFC obligations would be assigned to Northern California retailers and the Southern California SFPFC obligation would be assigned to Southern California retailers. By having fewer load nodes included in the clearing prices for Northern and Southern California SFPFCs, price spikes at individual nodes in these regions would have a greater impact of the clearing price and therefore provide stronger incentives for suppliers to minimize the cost serving demand in both Northern and Southern California.

4. Final Comments

Wholesale market design is a process of continuous learning, adaption, and hopefully, improvement. The transition of the California electricity supply industry from a system based on controllable natural gas-fired generation units to a system based on intermittent wind and solar resources and controllable energy from electricity imports requires a change in the market design. The standardized energy contracting approach to long-term resource adequacy described in this paper is designed to achieve a reliable supply energy under all possible future system conditions for this new industry structure.

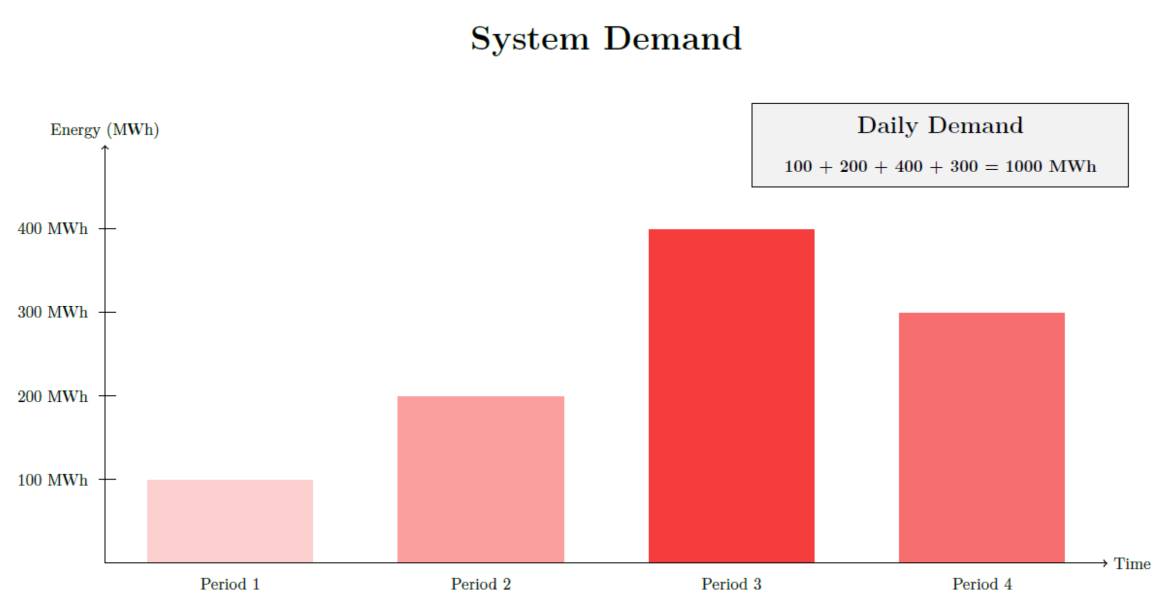

Figure 1: Hourly System Demands

Three Firms:

Firm 1 sells 300 MWh

Firm 2 sells 200 MWh

Firm 3 sells 500 MWh

Total Amount Sold by Three Firms = 1000 MWh

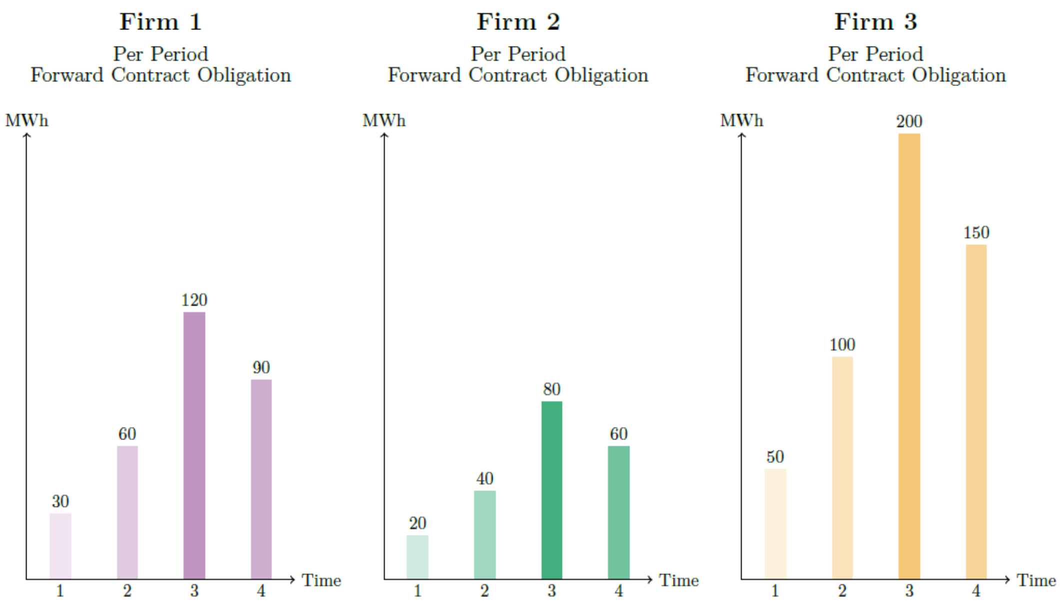

Figure 2: Hourly Forward Contract Quantities for Three Suppliers

Four Retailers:

Retailer 1 holds 100 MWh

Retailer 2 holds 200 MWh

Retailer 3 holds 300 MWh

Retailer 4 holds 400 MWh

Total Amount Held by Four Retailers = 1000 MWh

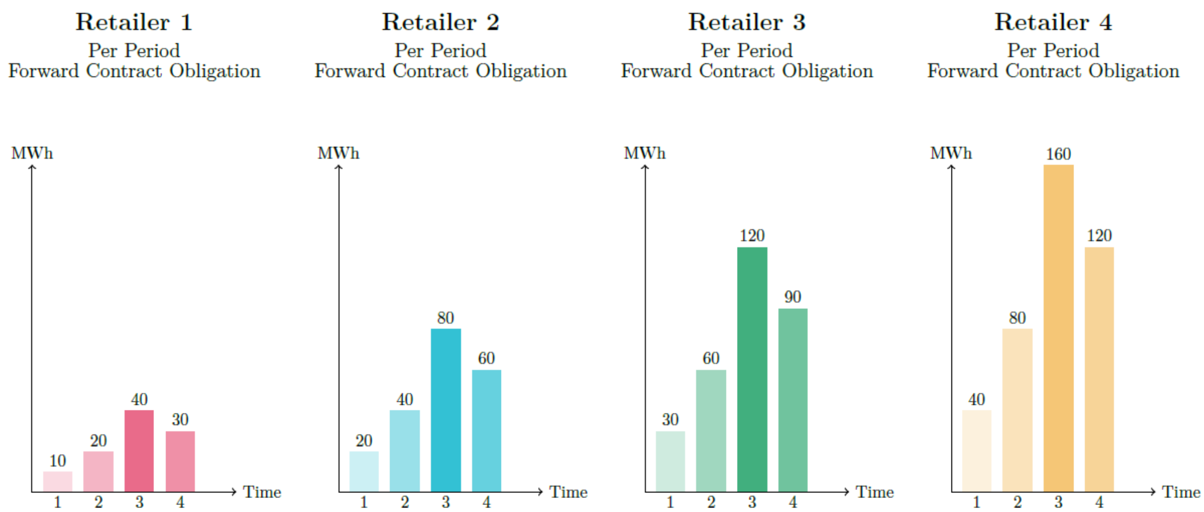

Figure 3: Hourly Forward Contract Quantities for Four Retailers

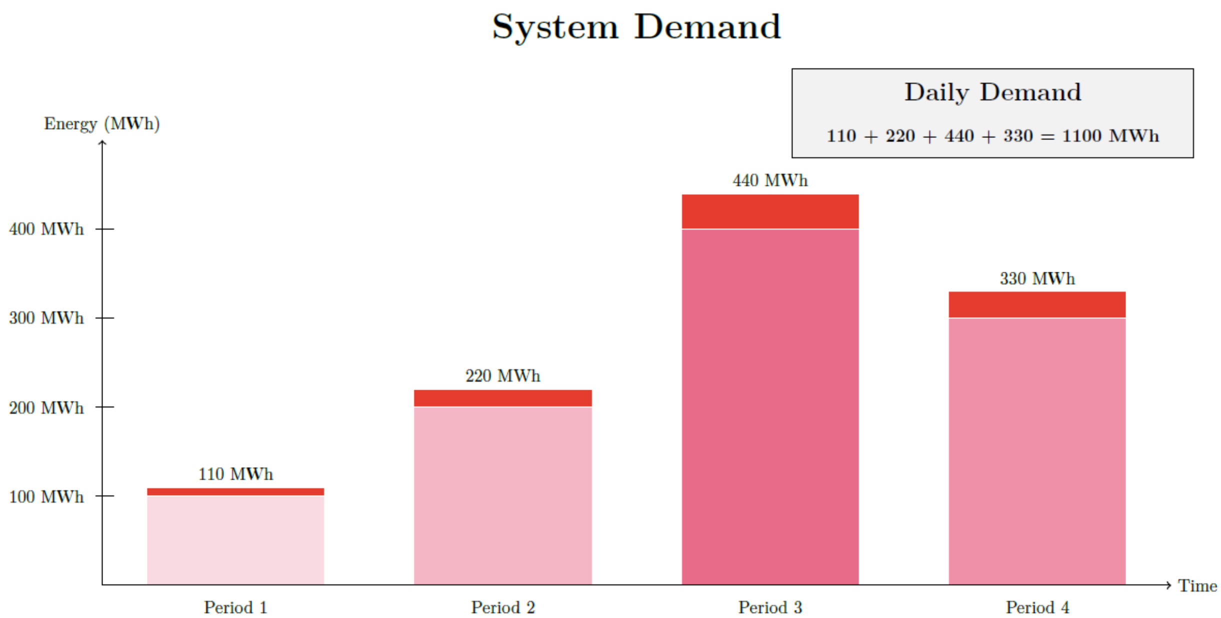

Figure 4: Hourly System Demands (10 Percent Higher)

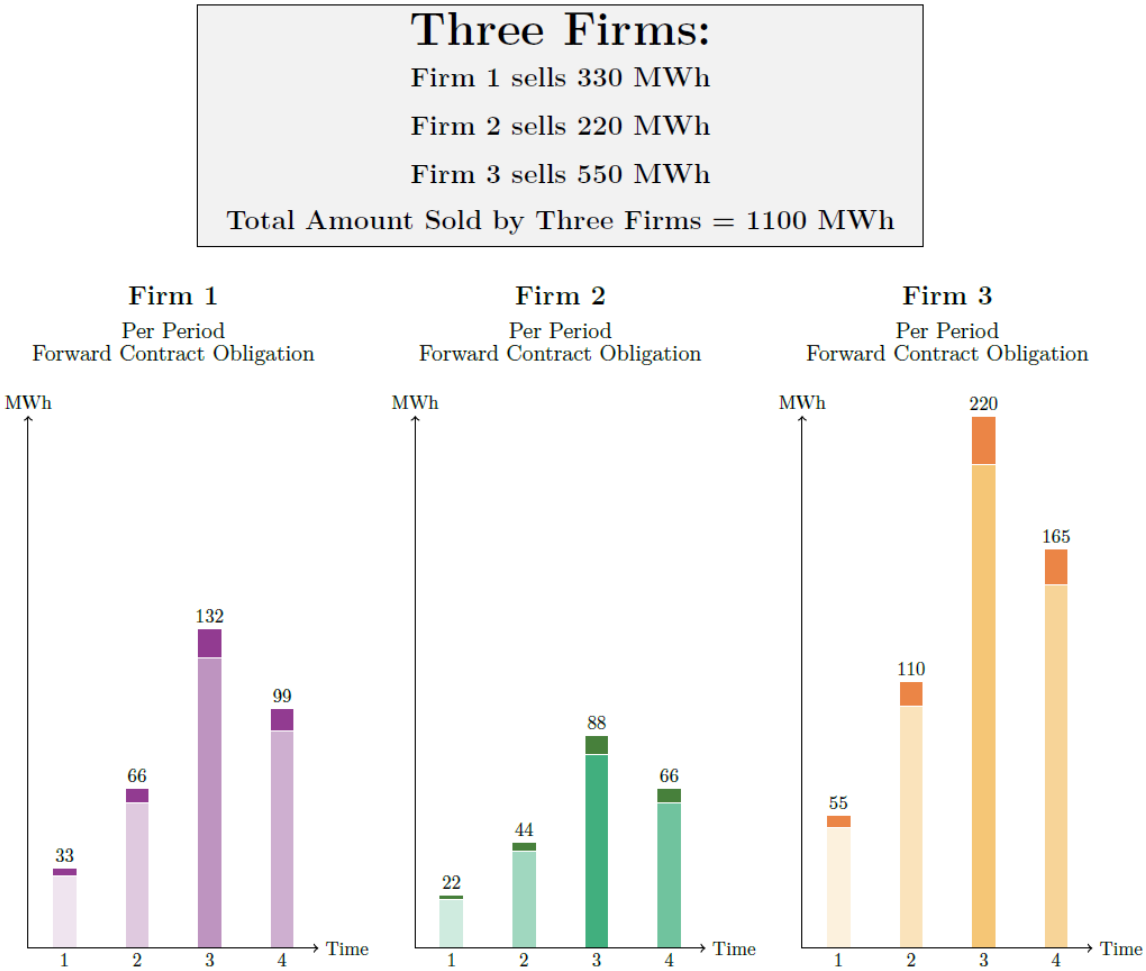

Figure 5: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Higher)

Four Retailers:

Retailer 1 holds 110 MWh

Retailer 2 holds 220 MWh

Retailer 3 holds 330 MWh

Retailer 4 holds 440 MWh

Total Amount Held by Four Retailers = 1100 MWh

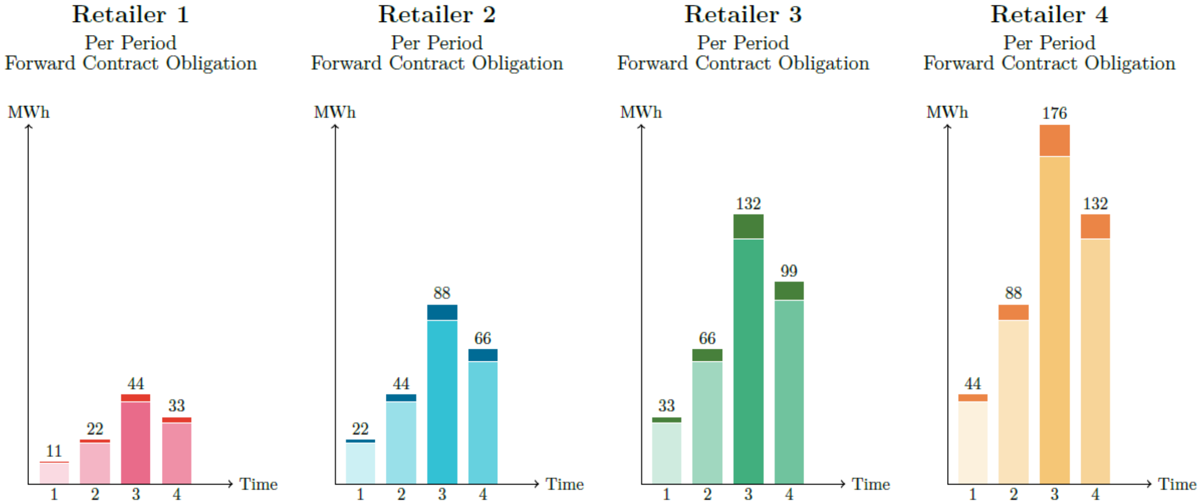

Figure 6: Hourly Forward Contract Quantities for Four Retailers (10 Percent Higher)

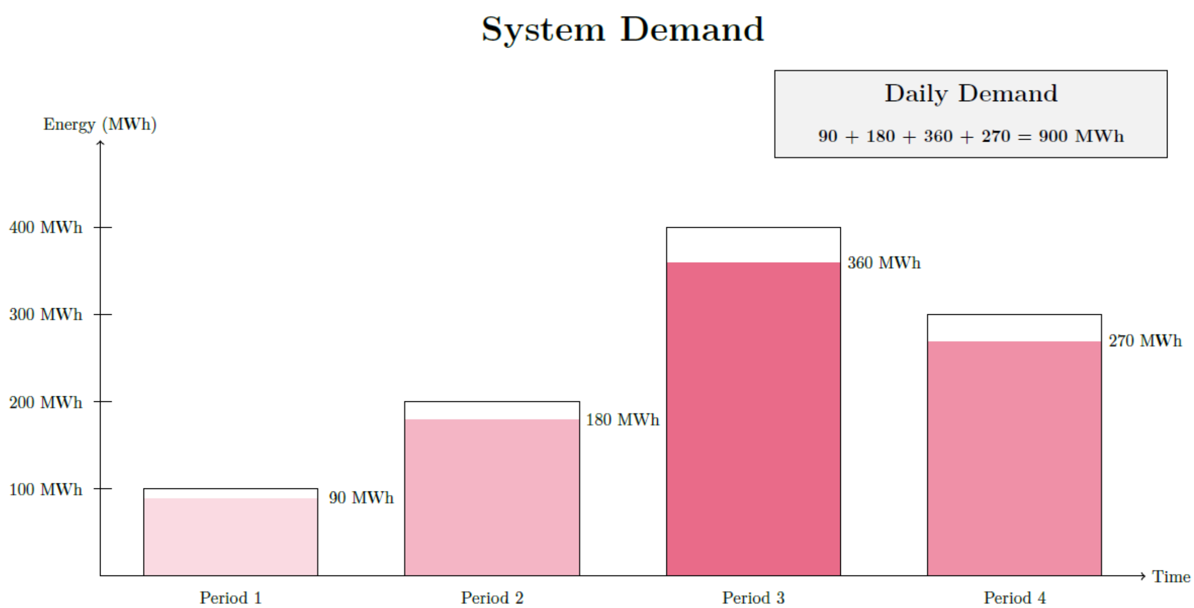

Figure 7: Hourly System Demands (10 Percent Lower)

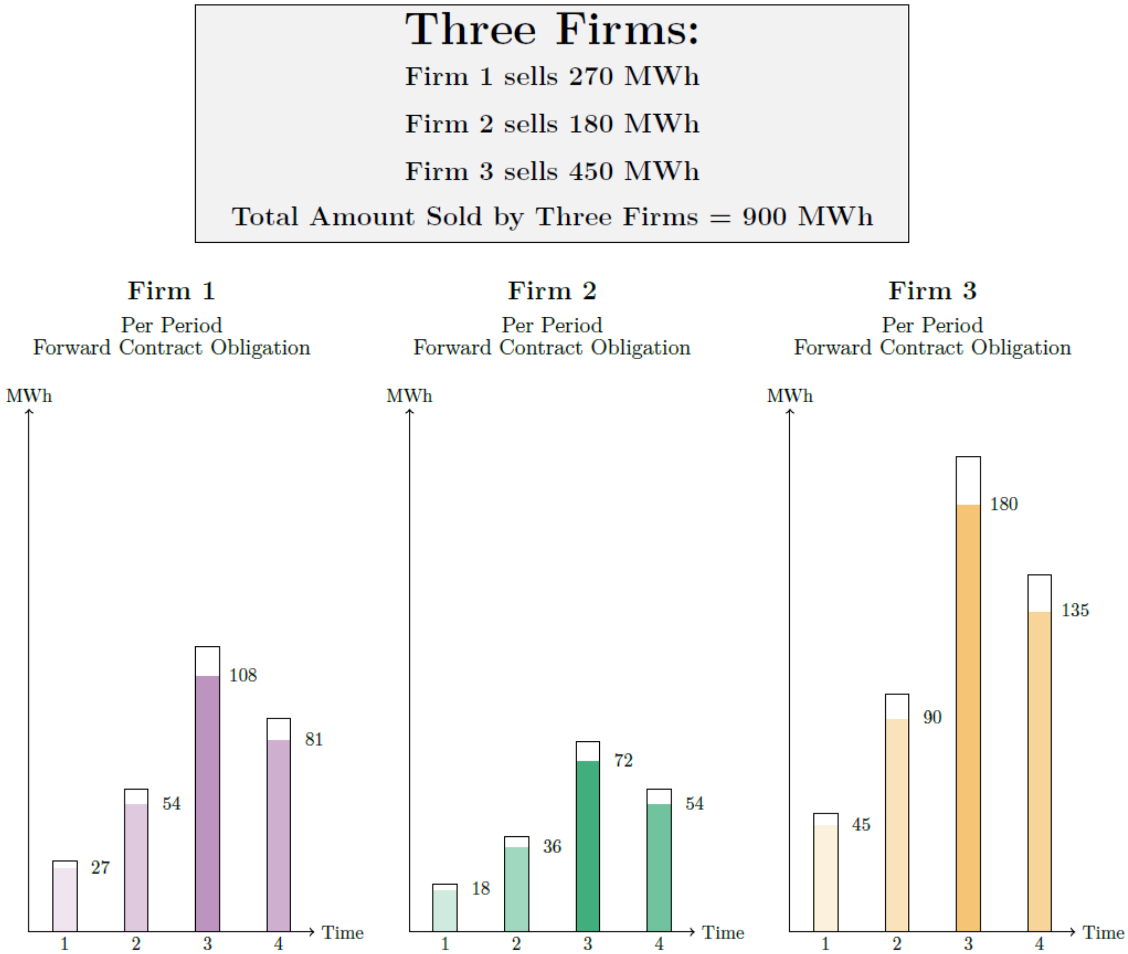

Figure 8: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Lower)

Four Retailers:

Retailer 1 holds 90 MWh

Retailer 2 holds 180 MWh

Retailer 3 holds 270 MWh

Retailer 4 holds 360 MWh

Total Amount Held by Four Retailers = 900 MWh

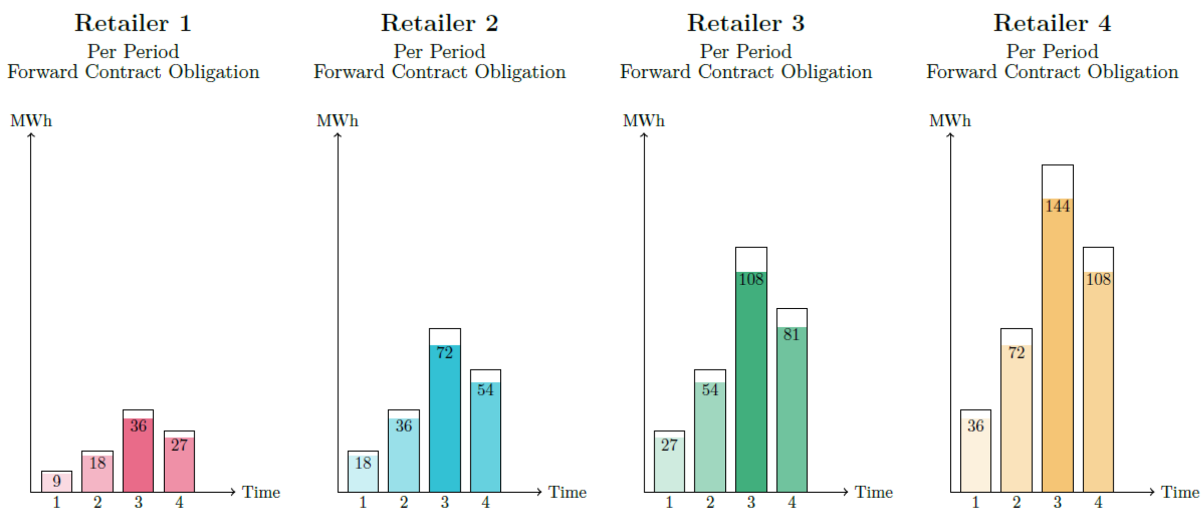

Figure 9: Hourly Forward Contract Quantities for Four Retailers (10 Percent Lower)